ATTACHMENT C: TESTING AND MONITORING PLAN 40 CFR 146.90

CLEAN ENERGY SYSTEMS MENDOTA

1. Facility Information

Facility name:	CLEAN ENERGY SYSTEMS MENDOTA MENDOTA_INJ_1
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Well location:	MENDOTA, FRESNO COUNTY, CA LAT/LONG COORDINATES (36.75585015/-120.36440423)

This Testing and Monitoring Plan describes how Clean Energy Systems will monitor the Clean Energy Systems Mendota site pursuant to 40 CFR 146.90. In addition to demonstrating that the well is operating as planned, the carbon dioxide plume and pressure front are moving as predicted, and that there is no endangerment to USDWs, the monitoring data will be used to validate and adjust the geological models used to predict the distribution of the CO_2 within the storage zone to support AoR reevaluations and a non-endangerment demonstration.

Results of the testing and monitoring activities described below may trigger action according to the (Schlumberger, Attachment F: Emergency and Remedial Response Plan, 2020).

This attachment is one of the several documents listed below that was prepared by Schlumberger and delivered to Clean Energy Systems. These documents were prepared to support the Clean Energy Systems preconstruction application to the EPA.

- (Schlumberger, Attachment A: Summary of Requirements Class VI Operating, 2020)
- (Schlumberger, Attachment B: Area of Review and Corrective Action Plan, 2020)
- (Schlumberger, Attachment C: Testing and Monitoring Plan, 2020)
- (Schlumberger, Attachment D: Injection Well Plugging Plan, 2020)
- (Schlumberger, Attachment E: Post-Injection Site Care and Site Closure Plan, 2020)
- (Schlumberger, Attachment F: Emergency and Remedial Response Plan, 2020)
- (Schlumberger, Attachment G: Construction Details Clean Energy Systems Mendota, 2020)
- (Schlumberger, Attachment H: Financial Assurance Demonstration, 2020)
- (Schlumberger, Class VI Permit Application Narrative, 2020)
- (Schlumberger Quality Assurance and Surveillance Plan, 2020)

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1.1 Acronyms and Abbreviations

*: Denotes a Mark of Schlumberger

AoR: Area of review

BFS: Base of fresh water

BGS: Below ground surface

CCS: Carbon capture and storage

CEMA: California Emergency Management Agency

CES: Clean Energy Systems

CNE: Carbon negative energy

DFN: Discrete fracture network

DST: Drill stem test

DT: Compressional slowness

DTS: Distributed temperature sensing

EPA: Environmental Protection Agency

FMI: Formation microimager

GRFS: Gaussian random function simulation

GR: Gamma ray

GS: Geological sequestration

KH: Permeability thickness

KINT: Permeability

Mendota_INJ_1: Proposed CO_2 Injection Well

MIT: Mechanical integrity test

MWD: Measurement while drilling

NPHI: Neutron porosity

PISC: Post injection Site Care

PHIT: Total porosity

PIGE: Effective porosity

RHOB: Bulk density

Rwa: Formation water resistivity

SGR: Shale gouge ratio

Shmax: maximum horizontal stress

Shmin: minimum horizontal stress

SP: Spontaneous potential

USDW: Underground sources of drinking water

VCL: Volume clay

VSP: Vertical Seismic profile

Vp/Vs: Compressional to shear velocity ratio

XRD: X-Ray diffraction analysis

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2. Overall Strategy and Approach for Testing and Monitoring

The Clean Energy Systems Carbon Capture and Storage (CES-CCS) Project' site development and monitoring, verification, and accounting (MVA) program detailed in the quality assurance surveillance plan (QASP) (Schlumberger Quality Assurance and Surveillance Plan, 2020) will be used to ensure safe underground storage of injected CO_2 and USDW non-endangerment.

A pre-construction AoR delineation model was constructed using public and purchased data including three 2D seismic lines, well logs and regional information from (USGS, 2019), (IHS, 2019), (TGS, 2019) and (DOGGR, 2019). The Second Panoche sandstone is identified as CO_2 sequestration formation with the First Panoche shale layer above. Above the Second Panoche are the 1st Panoche sand and the Moreno formations. The Moreno formation is laterally continuous in the region and identified as the main seal. The top of the Moreno formation is about 7,330 ft and the lowermost USDW is estimated at 1,415 ft. Seismic activity in the area has been very low with no large seismic events within the AoR. A future 3D seismic survey and characterization well will provide site-specific geophysical data to improve the AoR delineation model and help identify any additional risks.

The characterization well will core the Moreno main seal and Panoche sandstones intended for underground storage of CO_2 and will have a comprehensive suite of well logs, fluid sampling and core testing program detailed in (Schlumberger, Attachment G: Construction Details Clean Energy Systems Mendota, 2020). The characterization well evaluation program is designed to reduce geophysical, geomechanical and reservoir model uncertainties as well as ensure mechanical integrity of the well.

This CES-CCS project will use the characterization well as the injector (Mendota_INJ_1) and construct three monitoring wells (Figure 1). The locations of these wells are preliminary and expected to be moved as this project develops:

- Mendota_INJ_1: Characterization well and CO_2 injection well
- Mendota OBS_1: Monitoring the Panoche injection interval,
- Mendota ACZ_1: Monitoring the first permeable formation above the Moreno, currently identified as the Garzas formation,
- Mendota USDW_1: Monitoring well in the deepest USDW.
- GW1, GW2, GW3 and GW4: Nested shallow groundwater monitoring wells used to monitor the shallow aquifers around the site. The depth of these groundwater monitoring wells will be determining when the groundwater characteristics of the site are better understood. These wells are expected to be shallow in the range of 50 feet to 500 feet in depth.

The Mendota_OBS_1 Panoche monitoring well will be placed at a distance and direction from the injection well to optimize verification and calibration of the reservoir AoR delineation model and monitor plume migration. The distance and direction of the Panoche monitoring well will be where the reservoir AoR delineation model shows detectable pressure change within 6 months and CO_2 saturation of 10 to 20% within approximately one year. The well will be instrumented with continuously monitored pressure and temperature gauges and distributed temperature and acoustic fiber (DAS). Pressure, temperature and acoustic monitoring will provide early warning of parameters outside of the predicted model and operational limits including microseismic events near the injection site. The Panoche monitoring well will have sampling capability of the Panoche injection sands.

The Mendota ACZ1 monitoring well for the first permeable sandstone above the Moreno seal will provide early warning of any leakage past the Moreno seal. The well will be instrumented with continuously monitored pressure and temperature gauges and distributed temperature and acoustic fiber (DAS). Pressure, temperature and acoustic monitoring will provide early warning leakage of CO_2 past the Moreno seal as well as microseismic events near the injection site. The well will be placed in the up dip direction of Moreno formation or in the event a potential fault is identified on the 3D seismic within the AoR, in the direction of the fault intersection of the Moreno formation.

The Mendota USDW_1 is an underground source of drinking water (USDW) monitoring well and will be placed near the injection well within 1000 feet. The lowest formation with USDW will be verified with formation sampling in the characterization well. The USDW monitoring well will have sampling capability of the USDW.

This testing and monitoring plan and the (Schlumberger Quality Assurance and Surveillance Plan, 2020) detail the continuous pressure, temperature and acoustic monitoring of the injection and monitoring wells, and periodic sampling and well logging used to ensure safe operation and storage of the injected the CO_2. The testing and monitoring plan and the (Schlumberger Quality Assurance and Surveillance Plan, 2020) will provide early warning of any operational or well integrity problems and ensure USDW non-endangerment.

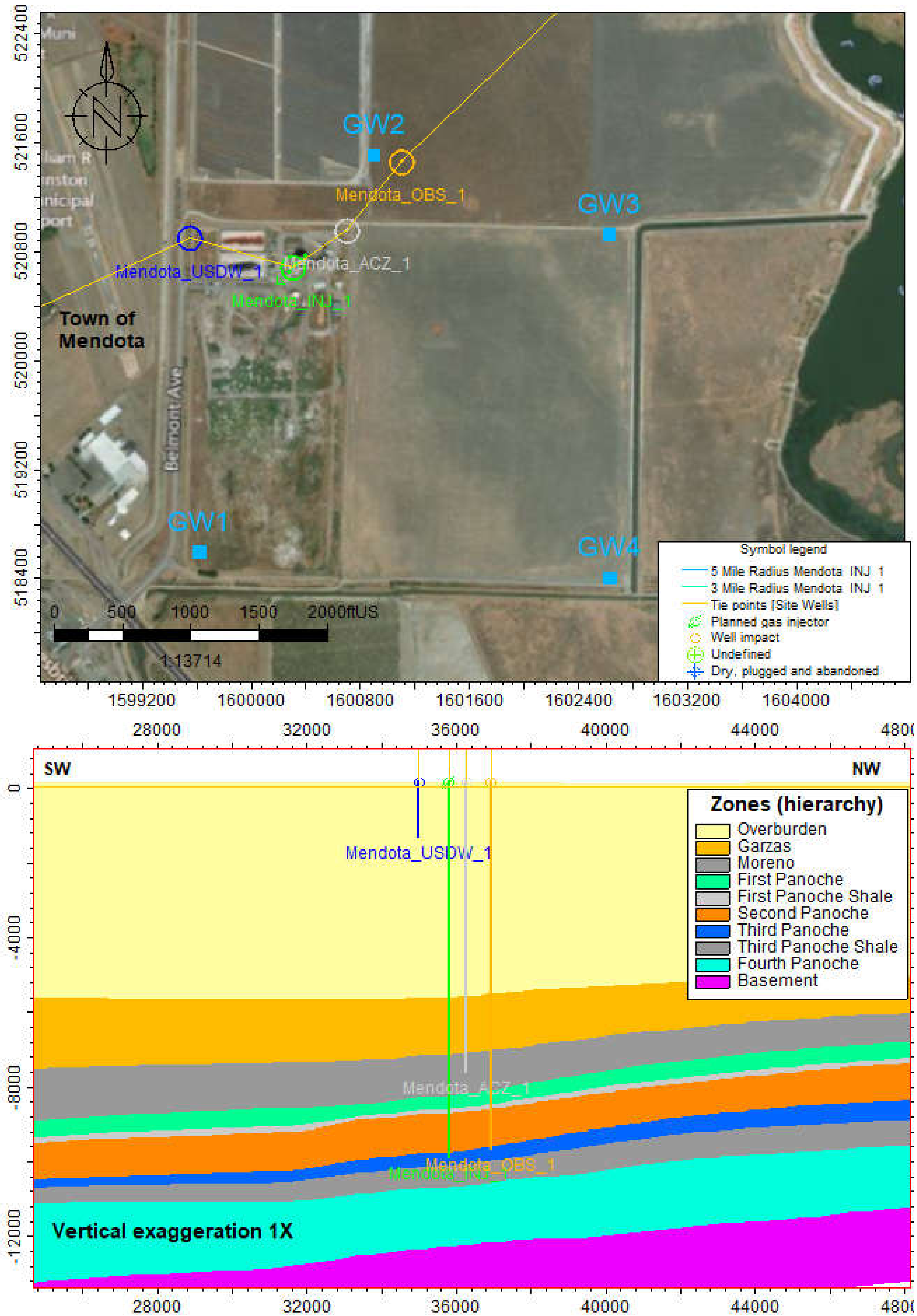


Figure 1: Clean Energy Systems well locations

2.1 Quality assurance procedures

The (Schlumberger Quality Assurance and Surveillance Plan, 2020) requires site specific data that has not been collected in this prepermitting phase of this project. Once these data are collected in future phases of this project, CES will have the details necessary to develop a comprehensive Quality Assurance and Surveillance Plan. A preliminary (Schlumberger Quality Assurance and Surveillance Plan, 2020) has been submitted with this pre-construction Class VI application.

2.2 Reporting procedures

Clean Energy Systems will report the results of all testing and monitoring activities to the EPA in compliance with the requirements under 40 CFR 146.91.

3. Carbon Dioxide Stream Analysis [40 CFR 146.90(a)]

Clean Energy Systems will analyze the CO_2 stream during the operation period to yield data representative of its chemical and physical characteristics and to meet the requirements of 40 CFR 146.90(a).

3.1 Sampling location and frequency

Sampling will take place quarterly, by the following dates each year: 3 months after the date of authorization of injection, 6 months after the date of authorization of injection, 9 months after the date of authorization of injection, and 12 months after the date of authorization of injection.

3.2 Analytical parameters

Clean Energy Systems will analyze the CO_2 for the constituents identified in Table 1 using the methods listed.

Table 1: Summary of analytical parameters for CO_2 stream.

Parameter	Analytical Method(s)[1]
Oxygen	ISBT 4.0 (GC/DID) GC/TCD
Nitrogen	ISBT 4.0 GC/DID GC/TCD
Carbon Monoxide	ISBT 5.0 Colorimetric ISBT 4.0 (GC/DID)
Oxides of Nitrogen	ISBT 7.0 Colorimetric
Ammonia	ISBT 6.0 (DT)
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)

Parameter	Analytical Method(s)[1]
CO_2 Purity	ISBT 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID) GC/TCD

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

3.3 Sampling methods

CO_2 stream sampling will occur after the last stage of compression. A sampling station will be installed with the ability to purge and collect samples into a container that will be sealed and sent to the authorized laboratory.

All sample containers will be labeled with durable labels and indelible markings. A unique sample identification number and sampling date will be recorded on the sample containers. The (Schlumberger Quality Assurance and Surveillance Plan, 2020) has more detail on this.

3.4 Laboratory to be used/chain of custody and analysis procedures

Samples will be analyzed by a third party laboratory using standardized procedures for gas chromatography, mass spectrometry, detector tubes, and photo ionization. The sample chain-of-custody procedures described in the (Schlumberger Quality Assurance and Surveillance Plan, 2020) will be employed.

4. Continuous Recording of Operational Parameters [40 CFR 146.88(e)(1), 146.89(b) and 146.90(b)]

Clean Energy Systems will install and use continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; the annulus fluid volume added; and the temperature of the CO_2 stream, as required at 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

4.1 Monitoring location and frequency

Clean Energy Systems will perform the activities identified in Table 2 to monitor operational parameters and verify internal mechanical integrity of the injection well. All monitoring will take place at the locations and frequencies shown in the table. The injection well will have pressure/temperature gauges at the surface and in the tubing at the packer. In addition, there will be distributed temperature sensing (DTS) fiber from surface to the tubing packer in the injection well.

Table 2: Sampling devices, locations, and frequencies for continuous monitoring.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection pressure		Surface	10 seconds	5 minutes (3)
Injection pressure		Reservoir – Proximate to packer	10 seconds	5 minutes (3)
Injection rate		Surface	10 seconds	5 minutes (3)
Injection volume		Surface	10 seconds	5 minutes (3)
Annular pressure		Surface	10 seconds	5 minutes (3)
CO_2 stream temperature		Surface	10 seconds	5 minutes (3)
Temperature		Reservoir – Proximate to packer	10 seconds	5 minutes (3)
Temperature	DTS	Along wellbore to packer	10 seconds	1 hour
Annulus fluid volume		Surface	4 hour	24 hour

Notes:

Note 1: Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
Note 2: Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.
Note 3: This can be the average of the sampled readings over the period, or maximum or minimum, as appropriate.

4.2 Monitoring details

Above-ground pressure and temperature instruments shall be calibrated over the full operational range at least annually using (American National Standards Institute (ANSI), n.d.) or other recognized standards. In lieu of removing the injection tubing, downhole gauges will demonstrate accuracy by using a second pressure gauge, with current certified calibration, that will be lowered into the well to the same depth as the permanent downhole gauge. Pressure transducers shall have a drift stability of less than 1 psi over the operational period of the instrument and an accuracy of ± 5 psi. Sampling rates will be at least once per 5 seconds. Temperature sensors will be accurate to within one degree Celsius.

Flow will be monitored with a mass flowmeter at the compression facility. The flowmeter will be calibrated using accepted standards and be accurate to within ± 0.1 percent. The flowmeter will be calibrated for the entire expected range of flow rates.

Injection Rate and Pressure Monitoring

Clean Energy Systems will monitor injection operations using the distributive process control system. The Surface Facility Equipment & Control System will limit maximum flow and/or limit the well head pressure to a pressure which corresponds to the regulatory requirement to not exceed 90% of the injection zone's fracture pressure. All injection operations will be continuously monitored and controlled by the Clean Energy Systems operations staff using the distributive process control system. This system will continuously monitor, control, record, and will alarm and shutdown if specified control parameters exceed their normal operating range.

More specifically, all critical system parameters, e.g., pressure, temperature, and flow rate will have continuous electronic monitoring with signals transmitted back to a master control system. Clean Energy Systems supervisors and operators will have the capability to monitor the status of the entire system from distributive control centers.

Calculation of Injection Volumes

Flow rate is measured on a mass basis (kg/hr). The downhole pressure and temperature data will be used to perform the injectate density calculation.

The volume of carbon dioxide injected will be calculated from the mass flow rate obtained from the mass flow meter installed on the injection line. The mass flow rate will be divided by density and multiplied by injection time to determine the volume injected.

Density will be calculated using the correlation developed by (Ouyang, 2011). The correlation uses the temperature and pressure data collected to determine the carbon dioxide density. The density correlation is given by:

$$\rho = A_0 + A_1*P + A_2*P^2 + A_3*P^3 + A_4*P^4$$

T is the temperature in degrees Celsius and the b coefficients are presented in Table 3 and Table 4 below.[1]

Table 3: Injection volume calculation b coefficients, pressure < 3000 psi.

	bi0	bi1	bi2	bi3	bi4
i=0	-2.148322085348E+05	1.168116599408E+04	-2.302236659392E+02	1.967428940167E+00	-6.184842764145E-03
i=1	4.757146002428E+02	-2.619250287624E+01	5.215134206837E-01	-4.494511089838E-03	1.423058795982E-05
i=2	-3.713900186613E-01	2.072488876536E-02	-4.169082831078E-04	3.622975674137E-06	-1.155050860329E-08
i=3	1.228907393482E-04	-6.930063746226E-06	1.406317206628E-07	-1.230995287169E-09	3.948417428040E-12
i=4	1.466408011784E-08	8.338008651366E-10	-1.704242447194E-11	1.500878861807E-13	4.838826574173E-16

Table 4: Injection volume calculation b coefficients, pressure >3000 psi.

	bi0	bi1	bi2	bi3	bi4
i=0	6.897382693936E+02	2.730479206931E+00	-2.254102364542E-02	-4.651196146917E-03	3 3.439702234956E-05
i=1	2.213692462613E-01	-6.547268255814E-03	5.982258882656E-05	2.274997412526E-06	-1.888361337660E-08
i=2	-5.118724890479E-05	2.019697017603E-06	-2.311332097185E-08	-4.079557404679E-10	3.893599641874E-12
i=3	5.517971126745E-09	-2.415814703211E-10	3.121603486524E-12	3.171271084870E-14	-3.560785550401E-16
i=4	-2.184152941323E-13	1.010703706059E-14	-1.406620681883E-16	-8.957731136447E-19	1.215810469539E-20

The final volume basis will be calculated as follows:

Volume basis (m3/hr) = Mass basis (kg/hr) / density (kg/m3)

Continuous Monitoring of Annular Pressure

Clean Energy Systems will use the procedures below to monitor annular pressure. The following procedures will be used to limit the potential for any unpermitted fluid movement into or out of the annulus:

1. The annulus between the tubing and the long string of casing will be filled with brine. The brine will have a specific gravity of 1.26 and a density of 9.4 lbs/gal. The hydrostatic gradient is 0.65 psi/ft. The brine will contain a corrosion inhibitor, scaling resistance, oxygen sequestering, and microbial growth inhibition.

2. The surface annulus pressure will be kept at a minimum of 1,142 pounds per square inch (psi) during injection.

3. During periods of well shut down, the surface annulus pressure will be kept at a minimum pressure to maintain a pressure differential of at least 100 psi between the annular fluid directly above (higher pressure) and below (lower pressure) the injection tubing packer.

4. The pressure within the annular space, over the interval above the packer to the confining layer, will be greater than the pressure of the injection zone formation at all times.

5. The pressure in the annular space directly above the packer will be maintained at least 100 psi higher than the adjacent tubing pressure during injection.

The annular monitoring system will consist of a continuous annular pressure gauge, a pressurized annulus fluid reservoir (annulus head tank), pressure regulators, and tank fluid level indication. The annulus system will maintain annulus pressure by controlling the pressure on the annulus head tank using either compressed nitrogen or CO_2.

The annulus pressure will be maintained between approximately 1,100-1,200 psi and monitored by the Clean Energy Systems control system gauges. The annulus head tank pressure will be controlled by pressure regulators–one set of regulators to maintain pressure above 1,100 psi by adding compressed nitrogen or CO_2 and the other to relieve pressure above 1,200 psi by venting gas off the annulus head tank.

Any changes to the composition of annular fluid will be reported in the next report submitted to the permitting agency.

If system communication is lost for greater than 30 minutes, project personnel will perform field monitoring of manual gauges every four hours or twice per shift for both wellhead surface pressure and annulus pressure and record hard copies of the data until communication is restored.

Average annular pressure and annulus tank fluid level will be recorded daily. The volume of fluid added or removed from the system will be recorded.

Casing-Tubing Pressure Monitoring

Clean Energy Systems will monitor the casing-tubing pressure as presented below.

During the injection timeframe of the project, the casing-tubing pressure will be monitored and recorded in real time. Surface pressure of the casing-tubing annulus is anticipated to be from 1000 to 1100 psi. As detailed in the Emergency and Remedial Response Plan (Attachment F to this permit), significant changes in the casing-tubing annular pressure attributed to well mechanical integrity will be investigated. Collection and recording of monitoring data will occur at the frequencies described in Table 2.

5. Corrosion Monitoring

To meet the requirements of 40 CFR 146.90(c), Clean Energy Systems will monitor injection well materials during the operation period for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance.

Clean Energy Systems will monitor corrosion using the corrosion coupon method and collect samples according to the description below.

5.1 Monitoring location and frequency

Clean Energy Systems corrosion monitoring using the corrosion coupon monitoring will occur quarterly, by the following dates each year: 3 months after the date of authorization of injection, 6 months after the date of authorization of injection, 9 months after the date of authorization of injection, and 12 months after the date of authorization of injection. Any break in operations will require an inspection of the coupon within 30 days of commencing operations, and return to the aforementioned schedule of three, six, nine and twelve months.

5.2 Sample description

Samples of material used in the construction of the compression equipment, pipeline and injection well which come into contact with the CO_2 stream will be included in the corrosion monitoring program either by using actual material and/or conventional corrosion coupons. The samples consist of those items listed in Table 5 below. Each coupon will be weighed, measured, and photographed prior to initial exposure (see "Sample Handling and Monitoring" below).

Table 5: List of equipment coupon with material of construction.

Equipment Coupon	Material of Construction
Pipeline	Carbon Steel
Long String Casing (surface)	Carbon Steel
Long String Casing (Below Packer)	Chrome Alloy
Injection Tubing	Chrome Alloy
Wellhead	Chrome Alloy
Packer	Chrome Alloy

5.3 Monitoring details

Sample Exposure

Each sample will be attached to an individual holder and then inserted in a flow through pipe arrangement. The corrosion monitoring system will be located downstream of all process compression/dehydration/pumping equipment (i.e., at the beginning of the pipeline to the wellhead). To accomplish this, a parallel stream of high pressure CO_2 will be routed from the pipeline through the corrosion monitoring system and then back into a lower pressure point upstream in the compression system. This loop will operate any time injection is occurring. No other equipment will act on the CO_2 past this point; therefore, this location will provide representative exposure of the samples to the CO_2 composition, temperature, and pressures that will be seen at the wellhead and injection tubing. The holders and location of the system will be included in the pipeline design and will allow for continuation of injection during sample removal.

Sample Handling and Monitoring

The coupons will be handled and assessed for corrosion using the (American Society for Testing and Materials (ASTM) G1-03, 1999), (Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens, 1999). The coupons will be photographed, visually inspected with a minimum of 10x power, dimensionally measured (to within 0.0001 inch), and weighed (to within 0.0001 gm).

Additional Wellbore Tests

Wireline logs to investigate downhole corrosion to supplement surface measurements. Downhole logging data will be performed prior to commencing injection operations. These logs will provide a baseline casing thickness measurement to which future logs will be compared. These logs can be used to verify reading obtained from surface monitoring equipment. Logging tools will include Ultrasonic Imaging Tool, Magnetic Flux Leakage, and Electro-Magnetic Imaging as these technologies are proven and widely accepted within the industry for their accuracy in determining casing thickness and identifying casing corrosion. Subsequent logs using the same technology will be run at one-year intervals thereafter. Results will be compared to the initial baseline log. Thickness measurements showing a reduction in thickness greater than twenty percent of API published nominal thickness will warrant further investigation.

6. Above Confining Zone Monitoring

Clean Energy Systems will monitor ground water quality and geochemical changes above the confining zone during the operation period to meet the requirements of 40 CFR 146.90(d).

To meet the requirements at 40 CFR 146.95(f)(3)(i), Clean Energy Systems will also monitor ground water quality, geochemical changes, and pressure in the first USDWs immediately above and below the injection zone(s).

The groundwater monitoring plan focuses on the following zones:

- Quaternary– the shallow groundwater (source of local drinking water).
- Santa Margarita or shallow undifferentiated sands – the lowermost USDW.
- Garza Formation – first permeable zone above the Moreno Shale confining zone.

6.1 Monitoring location and frequency

Table 6 shows the planned monitoring methods, locations, and frequencies for ground water quality and geochemical monitoring above the confining zone.

Table 6: Monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency[1-6]
Quaternary / Shallow strata sources of drinking water	Fluid sampling	Shallow monitoring wells GW1, GW2, GW3, GW4	4 shallow monitoring wells each with one sampling interval	Baseline; Year 1-2: Quarterly Year 3-5 yrs post injection: Annual
Santa Margarita or base of USDW (~1400 ft TVDSS)	Fluid sampling	Mendota USDW 1	1 point location	Baseline; Year 1-2: Quarterly Year 3-5 years post injection: Annual

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency[1-6]
	DAS – Distributed Temperature / Acoustic	Mendota ACZ 1	Distributed measurement	Continuous
	DAS – Distributed Temperature / Acoustic	Mendota OBS 1	Distributed measurement	Continuous
Garzas (5604 – 7132 TVDSS)	Fluid sampling	Mendota OBS 1	1 point location	Baseline; Year 1-end of injection: Annual
	DAS – Distributed Temperature / Acoustic	Mendota ACZ 1	Distributed measurement	Continuous
	DAS – Distributed Temperature / Acoustic	Mendota OBS 1	Distributed measurement	Continuous
	Pulsed Neutron	Mendota ACZ 1	Survey Log	Baseline; Year 1-1.5: Quarterly Year 1.5- through injection period: Annual
	Pulsed Neutron	Mendota OBS 1	Survey Log	Baseline; Year 1-1.5: Quarterly Year 1.5- through injection period: Annual

Note 1: Baseline sampling and analysis will be completed before injection is authorized.
Note 2: Quarterly sampling will take place by the following dates each year: 3 months after the date of authorization of injection, 6 months after the date of authorization of injection, 9 months after the date of authorization of injection, and 12 months after the date of authorization of injection.
Note 3: Semi-annual sampling will be performed each year by: 6 months after the date of authorization of injection and 12 months after the date of authorization of injection.
Note 4: Annual sampling will occur up to 45 days before the anniversary date of authorization of injection each year.
Note 5: Continuous monitoring is described in Table 2 of this plan
Note 6: Changes to the ground water monitoring frequency will be with the UIC Program Directors prior approval.

The location of shallow groundwater and above confining zone monitoring wells will be determined in future phases of the project when a more detailed groundwater evaluation is completed. Pulsed neutron is capable of making several different measurements sensitive to CO2 in the formation and in the casing-formation annulus. Therefore, pulsed neutron can be used to monitor the formation fluids as well as identify mechanical integrity problems that may allow the CO2 to migrate up the casing annuli.

Figure 2 shows the AoR delineation model for the first 6 months of injection. The Mendota OBS_1 Panoche monitoring well will be placed at a distance and direction from the injection well to optimize verification and calibration of the reservoir AoR delineation model and monitor plume migration. The distance and direction of the Mendota OBS 1 will be where the reservoir AoR delineation model shows detectable pressure change within 6 months and / or CO_2 saturation of 10 to 20% within approximately one year. The Mendota ACZ_1 monitoring well for the first permeable sand above the Moreno seal will provide early warning of any leakage past the Moreno seal. The well will be placed in the up-dip direction of Moreno formation or in the event a potential fault is identified in the baseline 3D seismic within the AoR, in the direction of the fault intersection of the Moreno formation.

The baseline 3D will provide the basis for imaging the initial reservoir conditions prior to injection and should cover an area sufficiently large enough to tie into key calibration wells in the region and primary sub-regional structure that may impact the migrating injection plume over an extended time period. As the injected CO_2 will change the seismic velocity and amplitude signature, the plume migration can be monitored with the acquisition time lapse or repeat of 3D seismic or 3D VSP the at later stages of injection. While it is expected that the seismic signature resulting from injection into these relatively compressible sand shale sequences in the AOR subsurface to be quite evident, it is recommended to model the prestack seismic signature with simulated fluid injection to determine the degree of sensitivity. Based on the modeling response, the time-lapse seismic monitoring program (3D surface or 3D VSP surveys) can be effectively designed to monitor the plume over time. Furthermore, the area of needed coverage (and method) can be tailored to the anticipated size of the injected plume based upon the injection simulation (shown in the example below).

Pulsed neutron is capable of making several different measurements sensitive to CO_2 in the formation and in the casing-formation annulus. Therefore, pulsed neutron can be used to monitor the formation fluids as well as identify mechanical integrity problems that may allow the CO_2 to migrate up the casing annuli.

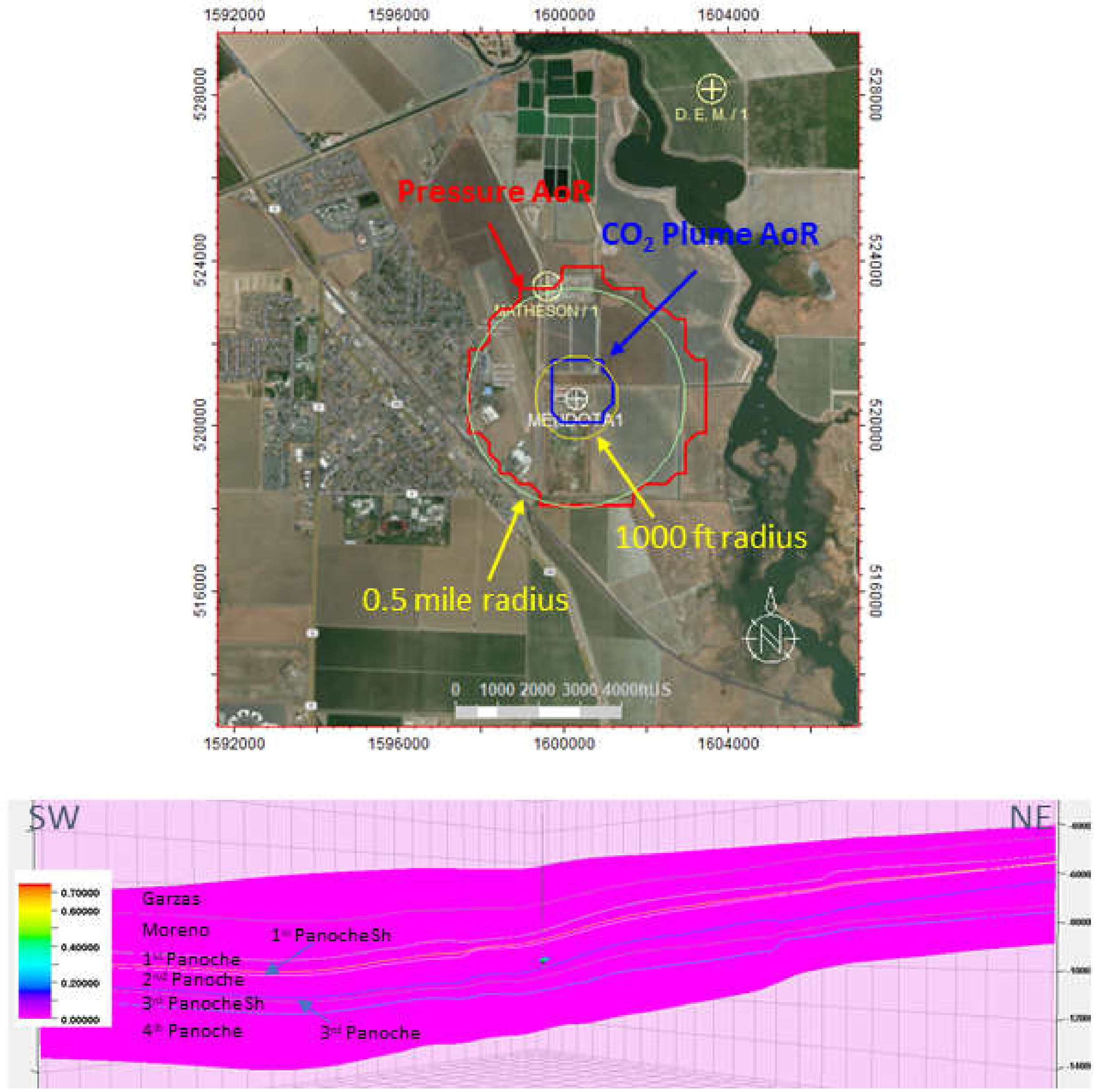


Figure 2: AoR delineation model for 6 months injection

6.2 Analytical parameters

Table 7 identifies the parameters to be monitored and the analytical methods Clean Energy Systems will use. This analytical package is comprehensive enough to meet the site-specific monitoring objectives. If additional methods are required, they will be added during the life of the project.

Table 7: Summary of analytical and field parameters for ground water samples.

Parameters	Analytical Methods [1]
Quaternary / Shallow strata sources of drinking water	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, and Tl	ICP-MS, EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B
Anions: Br, Cl, F, NO_3, and SO_4	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	Coulometric titration, ASTM D513-11
Total Dissolved Solids	Gravimetry; Method 2540 C [1]
Alkalinity	Method 2320 B [1]
pH (field)	EPA 150.1
Specific conductance (field)	Method 2510-B [1]
Temperature (field)	Thermocouple
Santa Margarita or base of USDW	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, and Tl	ICP-MS, EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B
Anions: Br, Cl, F, NO_3, and SO_4	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	Coulometric titration, ASTM D513-11
Isotopes: $\delta^{13}C$ of DIC	Isotope ratio mass spectrometry
Total Dissolved Solids	Gravimetry; Method 2540 C [1]
Alkalinity	Method 2320 B [1]
pH (field)	EPA 150.1
Specific conductance (field)	Method 2510-B [1]
Temperature (field)	Thermocouple
Garzas	

Parameters	Analytical Methods [1]
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, and Tl	ICP-MS, EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B
Anions: Br, Cl, F, NO_3, and SO_4	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	Coulometric titration, ASTM D513-11
Isotopes: $\delta^{13}C$ of DIC	Isotope ratio mass spectrometry
Total Dissolved Solids	Gravimetry; Method 2540 C [1]
Alkalinity	Method 2320 B [1]
pH (field)	EPA 150.1
Specific conductance (field)	Method 2510-B [1]
Temperature (field)	Thermocouple

Note 1: ICP = inductively coupled plasma; MS = mass spectrometry; OES = optical emission spectrometry; GC-P = gas chromatography - pyrolysis. An equivalent method may be employed with the prior approval of the UIC Program Director.

6.3 Sampling methods

Sampling will be performed as described in Section B.2 of the (Schlumberger Quality Assurance and Surveillance Plan, 2020); this describes the groundwater sampling methods to be employed, including sampling SOPs (Section B.2.a/b), and sample preservation (Section B.2.g).

Sample handling and custody will be performed as described in Section B.3 of the (Schlumberger Quality Assurance and Surveillance Plan, 2020).

Quality control will be ensured using the methods described in Section B.5 of the (Schlumberger Quality Assurance and Surveillance Plan, 2020).

6.4 Laboratory to be used/chain of custody procedures

Samples will be analyzed by a third party laboratory using standardized procedures for gas chromatography, mass spectrometry, detector tubes, and photo ionization. The sample chain-of-custody procedures described in the (Schlumberger Quality Assurance and Surveillance Plan, 2020) will be employed.

7. External Mechanical Integrity Testing

Clean Energy Systems will conduct at least one of the tests presented in Table 8 periodically during the injection phase to verify external mechanical integrity as required at 146.89(c) and 146.90.

7.1 Testing location and frequency

Mechanical integrity testing (MITs) will be performed annually, up to 45 days before the anniversary date of authorization of injection each year or alternatively scheduled with the prior approval of the UIC Program Director

MIT logs pulsed neutron will occur quarterly, by the following dates each year: 3 months after the date of authorization of injection, 6 months after the date of authorization of injection, 9 months after the date of authorization of injection, 12 months after the date of authorization of injection, 15 months after the date of authorization of injection, 18 months after the date of authorization of injection and then annually up to 45 days before the anniversary date of authorization of injection each year or will be alternatively scheduled with the prior approval of the UIC Program Director.

Casing Inspection Logs

MIT ultra-sonic logs will monitor the presence or absence of corrosion of the injection (Mendota INJ 1) or monitoring wells (Mendota OBS 1 and Mendota ACZ 1) during any workover operation requiring the tubing to be removed, allowing for larger diameter inspection tools and evaluation of the casing behind the well tubing.

Table 8: Mechanical integrity testing (MIT).

Test Description	Location
Temperature Log / Survey	Along wellbore using Distributed Temperature Sensing (DTS) or conventional wireline well log
Oxygen Activation Log	Wireline Well Log
Pulsed Neutron Logging	Wireline Well Log
Acoustic (or Noise) Log/Survey coupled with Temperature Log/Survey	Along wellbore using Distributed Acoustic Sensing (DAS); DAS equivalent or conventional wireline well log

7.2 Testing details

7.2.1.1 Temperature Logging Using Wireline

To ensure the mechanical integrity of the casing of the injection well, temperature data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided. The following procedures will be employed for temperature logging:

The well should be shut-in from injection a minimum of 24 hours prior to logging. This will allow the majority of the well to return to near natural geothermal temperature with the exception of the injection zone.

1. Move in and rig up an electrical logging unit with lubricator.

2. With the well still shut-in run a temperature survey from the Base of the Santa Margarita Formation (or higher) to the deepest point reachable in the Panoche at a recommended 30 ft/min.[2]

3. Begin injection at the normal injection rate. Allow injection to stabilize for a recommended 6 hours

4. Run a temperature survey from the Base of the Santa Margarita Formation (or higher) to the deepest point reachable in the Panoche while injecting at a rate that allows for safe operations at a recommended 30 ft/min.[2]

5. Stop injection, pull tool back to shallow depth, wait 1 hour.

6. Run a temperature survey over the same interval as step 4.

7. Pull tool back to shallow depth, wait 2 hours.

8. Run a temperature survey over the same interval as step 4.

9. Pull tool back to shallow depth, wait 2 hours.

10. Run a temperature survey over the same interval as step 4.

11. Evaluate data to determine if additional passes are needed for interpretation. Should CO_2 migration be interpreted in the top most section of the log, additional logging runs over a higher interval will be required to find the top of migration.

12. If additional passes are needed, repeat temperature surveys every 2 hours until 12 hours, over the same interval as step 4.

13. Rig down the logging equipment.

14. Data interpretation involves comparing the time lapse well temperature profiles and looking for temperature anomalies that may indicate a failure of well integrity; i.e. tubing leak or movement of fluid behind the casing. As the well cools down the temperature profile along the length of the tubing string is compared to the baseline. Any unplanned fluid movement into the annulus or outside the casing creates a temperature anomaly when compared to the baseline cooling profile.

[2]Should operational constraints or safety concerns not allow for a logging pass while injecting, an acceptable, alternate plan is to stop injecting immediately prior to the first logging pass.

7.2.1.2 Temperature Logging Using DTS Fiber Optic Line

Leaks may not be continuous or exhibit abnormal in flow behavior and therefore conventional temperature logs may not be adequate due to the nature of data collection. Fiber optics offers the ability to continuously and instantaneously monitor the entire length of fiber used in the well and a predetermined sample rate significantly improving the ability to resolve the leak point.

Mendota INJ 1 will be equipped with a DTS fiber optic temperature monitoring system that is capable of monitoring the injection well's annular temperature along the length of the tubing string instantaneously. The DTS line is used for real time temperature monitoring and, like a conventional temperature log, can be used for early detection of temperature changes that may indicate a loss of well mechanical integrity. The procedure for using the DTS for well mechanical integrity is as follows:

1. After the well is completed and prior to injection, a baseline temperature profile will be established. This profile represents the natural temperature gradient for each stratigraphic zone.

Or in the case when temporary (wireline) fiber optics is employed:

1(b.) Shut-in from injection a minimum of 24 hours prior to logging. This will allow the majority of the well to return to near natural geothermal temperature likely with the exception of the injection zone.

   a. Move in and rig up a fiber optic logging unit with lubricator.
   b. Record a baseline geothermal DTS survey for 1 hour
   c. Begin injection at the normal injection rate.

2. During injection operation, record the temperature profile for 6 hours prior to shutting in well.
3. Stop injection and record temperature profile for 6 hours.
4. Evaluate data to determine if additional warm back time is needed for interpretation.
5. Data interpretation involves comparing the time lapse well temperature profiles and looking for temperature anomalies that may indicate a failure of well integrity; i.e. tubing leak or movement of fluid behind the casing. The DTS system monitors and records the well's temperature profiles at a pre-set frequency in real time. As the well cools down the temperature profile along the length of the tubing string is compared to the baseline. Any unplanned fluid movement into the annulus or outside the casing creates a temperature anomaly when compared to the baseline cooling profile. This data can be continuously monitored to provide real time MIT surveillance making this technology superior to wireline temperature logging.

7.2.1.3 Oxygen Activation (OA) Logging

To ensure the mechanical integrity of the casing of the injection well, logging data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided. OA logging will be carried out while injection is occurring. The following procedures will be employed:

1. Move in and rig up an electrical logging unit with lubricator.

2. Conduct a baseline Gamma Ray Log and casing collar locator log from the top of the injection zone to the surface prior to taking the stationary readings with the OA tool.[3]

3. The OA log shall be used only for casing diameters of greater than 1-11/16 inches and less than 13- 3/8 inches.

4. All stationary readings should be taken with the well injecting fluid at the normal rate with minimal rate and pressure fluctuations.

5. Prior to taking the stationary readings, the OA tool must be properly calibrated in a “no vertical flow behind the casing” section of the well to ensure accurate, repeatable tool response and for measuring background counts.

6. Take, at a minimum, a 15 minute stationary reading adjacent to the confining interval located immediately above the injection interval. This must be at least 10 feet above the injection interval so that turbulence does not affect the readings.

7. Take, at a minimum, a 15 minute stationary reading at a location approximately midway between the base of the lowermost USDW and the confining interval located immediately above the injection interval.

8. Take, at a minimum, a 15 minute stationary reading adjacent to the top of the confining zone.

9. Take, at a minimum, a 15 minute stationary reading at the base of the lowermost USDW.

10. If flow is indicated by the OA log at a location, move up-hole or downhole as necessary at no more than 50 foot intervals and take stationary readings to determine the area of fluid migration.

11. Interpret the data: Identification of differences in the activated water’s measured gamma ray count-rate profile versus the expected count-rate profile for a static environment. Differences between the measured and expected may indicate flow in the annulus or behind the casing. The flow velocity is determined by measuring the time that the activated water passes a detector.

[3]Gamma Ray Log is necessary to evaluate the contribution of naturally occurring background radiation to the total gamma radiation count detected by the OA tool. There are different types of natural radiation emitted from various geologic formations or zones and the natural radiation may change over time.

7.2.1.4 Pulsed Neutron Logging Using Wireline

To ensure the mechanical integrity of the casing of the injection well, temperature data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided. A pre-injection baseline pulsed neutron log should be recorded. The following procedures will be employed for pulsed neutron logging:

The well should be in a state of injection for at least 6 hours prior to commencing operations in order to cool injection zones.

1. Move in and rig up an electrical logging unit with lubricator.

2. Run pulsed neutron survey from the Base of the Santa Margarita Formation (or higher) to the deepest point reachable in the Panoche. The Pulsar*, pulsed neutron tool should be run in Gas-Sigma-Hydrogen Index (GSH) mode.

3. Inspect Pulsar time-lapse measurements sensitive to the formation, borehole and annular space compared to pre-injection baseline to evaluate well integrity and detect CO_2 in the annular space or formations outside of the injection zone. Some of the measurements sensitive to the annular space are Sigma borehole (SIBH), Short-Spaced Sigma Near Apparent (SSNA), capture background corrected burst Gamma Ray count Rate (GRAT), Fast Neutron elastic scattering Cross-Section (FNXS), and Thermal Neutron Porosity (TPHI). SIBH is the measured Sigma or thermal neutron capture cross section of the borehole environment decreasing with the presence of CO_2. SIBH has a correction for the formation Sigma, so the raw uncorrected measurement SSNA which is the primary measurement for SIBH is also monitored. SSNA may have more sensitivity to annular CO_2 but must be evaluated considering changes in the near wellbore fluids, i.e. diffusion of fresh fluids present in the near wellbore from the well construction. TPHI is corrected for the borehole environment and is primarily sensitive to the formation. Annular CO_2 may decrease TPHI similar to formation CO_2 but can be masked by borehole corrections. FNXS has a shallow depth of investigation of around 4 in. and is sensitive to annular and formation CO_2.

7.2.1.5 Acoustic (or Noise) Log/Survey coupled with Temperature Log/Survey

To ensure the mechanical integrity of the casing of the injection well, the combination of acoustic, otherwise known as noise, and temperature data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided. The following procedures will be employed for acoustic (noise) and temperature logging:

For conventional tools is typical that temperature is logged in the downwards direction followed by a noise log in the upwards direction. Leaks occurring in the annulus of a wellbore will emit a sound as the fluids/gases flow to surface. Running an acoustic (noise) survey in addition to a temperature can provide significant additional information about the nature of the leak and assisting when multiple leak points are occurring. It is recommended that this combination or a form thereof is run in most survey applications.

The well should be shut-in from injection a minimum of 24 hours prior to logging. This will allow the majority of the well to return to near natural geothermal temperature with the exception of the injection zone.

1. Move in and rig up an electrical logging unit with lubricator.

2. With the well still shut-in run a temperature survey from the Base of the Santa Margarita Formation (or higher) to the deepest point reachable in the Panoche at a recommended 30 ft/min.[2]

3. Perform station stop noise logs at regular intervals, proceed to the next station stop in the upwards direction or in the case of a continuous capable noise tool, log in the upwards direction to establish the baseline.

4. Begin injection at the normal injection rate. Allow injection to stabilize for a recommended 6 hours

5. Log down with the temperature tool while injecting at a stable rate at a recommended logging speed of 30ft/min.

6. A noise survey at this point will be dominated by the noise of injection and is not required.

7. Stop injection, pull tool back to shallow depth, wait 1 hour.

8. Run a temperature survey over the same interval as step 2.

9. Perform station stop noise logs at regular intervals, proceed to the next station stop in the upwards direction or in the case of a continuous capable noise tool, log in the upwards direction to establish the baseline.

10. Pull tool back to shallow depth, wait 2 hours.

11. Run a temperature survey over the same interval as step 2, at a recommended logging speed of 30ft/min.

12. Perform station stop noise logs at regular intervals, proceed to the next station stop in the upwards direction or in the case of a continuous capable noise tool, log in the upwards direction to establish the baseline.

13. Pull tool back to shallow depth, wait 2 hours.

14. Run a temperature survey over the same interval as step 2, at a recommended logging speed of 30ft/min.

15. Perform station stop noise logs at regular intervals, proceed to the next station stop in the upwards direction or in the case of a continuous capable noise tool, log in the upwards direction to establish the baseline.

16. Evaluate data to determine if additional passes are needed for interpretation. Should CO_2 migration be interpreted in the top most section of the log, additional logging runs over a higher interval will be required to find the top of migration.

[2]Should operational constraints or safety concerns not allow for a logging pass while injecting, an acceptable, alternate plan is to stop injecting immediately prior to the first logging pass.

17. If additional passes are needed, repeat temperature surveys every 2 hours until 12 hours, over the same interval as step 2.

18. Rig down the logging equipment.

19. Data interpretation involves comparing the time lapse well temperature profiles and looking for temperature anomalies that may indicate a failure of well integrity; i.e. tubing leak or movement of fluid behind the casing. As the well cools down the temperature profile along the length of the tubing string is compared to the baseline. Any unplanned fluid movement into the annulus or outside the casing creates a temperature anomaly when compared to the baseline cooling profile. While similarly an acoustic signature will exist in the event of a leak. The frequency at which the leak will flow depends on if the CO2 is flowing as a gas, a liquid or a combination thereof. The survey should be acquired with both low and high frequency ranges simultaneously.

7.2.1.6 Acoustic and Temperature Logging Using Distributed Temperature Sensing (DTS) and Distributed Acoustic Sensing (DAS) or equivalent Fiber Optic Line

Leaks may not be continuous or exhibit abnormal in flow behavior and therefore conventional temperature logs may not be adequate due to the nature of data collection. Fiber optics offers the ability to continuously and instantaneously monitor the entire length of fiber used in the well and a predetermined sample rate significantly improving the ability to resolve the leak point.. A combination of DAS and DTS fiber optics is capable of monitoring the injection well's annular temperature and acoustic signature simultaneously and instantaneously along the length of the tubing or casing string. The DAS/DTS line is used for real time acoustic and temperature monitoring and, like a conventional temperature log, can be used for early detection of temperature changes that may indicate a loss of well mechanical integrity. The procedure for using the DAS/DTS for well mechanical integrity is as follows:

1. After the well is completed and prior to injection, a baseline acoustic and temperature profile will be established. This profile represents the natural temperature gradient for each stratigraphic zone and the natural acoustic state of the wellbore.

Or in the case when temporary (wireline) fiber optics is employed:

1(b.) Shut-in from injection a minimum of 24 hours prior to logging. This will allow the majority of the well to return to near natural geothermal temperature likely with the exception of the injection zone and reset to a background acoustic level.

   a. Move in and rig up a fiber optic logging unit with lubricator.

   b. Record a background DAS and baseline geothermal DTS survey for 1 hour

   c. Begin injection at the normal injection rate.

2. During injection operation, record the acoustic-temperature profile for 6 hours prior to shutting in well.

3. Stop injection and record acoustic-temperature profile for 6 hours.

4. Evaluate data to determine if additional warm-back time is needed for interpretation.

5. There is not a requirement to move fiber optics upwards or downwards in the well to collect data as the cable itself is the measuring device. Requirements to deploy on to bottom of the well or to the bottom logged interval. Data interpretation involves comparing the time lapse well acoustic and temperature profiles and looking for acoustic-temperature anomalies that may indicate a failure of well integrity; i.e. tubing leak or movement of fluid behind the casing. The DAS/DTS system monitors and records the well's temperature profiles at a pre-set frequency in real time. As the well cools down the temperature profile along the length of the tubing string is compared to the baseline. While similarly an acoustic signature will exist in the event of a leak. The frequency at which the leak will flow depends on if the CO2 is flowing as a gas, a liquid or a combination thereof. The survey should be acquired with both low and high frequency ranges simultaneously Any unplanned fluid movement into the annulus or outside the casing creates a acoustic and temperature anomaly when compared to the baseline profiles. This data can be continuously monitored to provide real time MIT surveillance making this technology superior to wireline temperature logging.

8. Pressure Fall-Off Testing

8.1 Purpose

The purpose of this test is to identify injection interval or wellbore problems and injection interval characteristics. It is the responsibility of the permittee to develop a testing procedure which will generate adequate data for a meaningful analysis.

8.2 Regulatory Citation

The Class VI Rule requires monitoring of the pressure buildup in the injection zone at least every five (5) years and more frequently if required by the UIC program director [40 CFR 146.90(f), including at a minimum, shut down of the well for a time sufficient to conduct a valid observation of the pressure falloff. This test is known as the formation pressure fall-off test.

8.3 Timing of Falloff Tests and Report Submission

Falloff tests must be conducted within one year from the date of the original petition approval and annually thereafter. The time interval for each test should not be less than 9 months or greater than 15 months from the previous test. This will ensure that the tests will be performed at relatively even intervals throughout the duration of the petition approval period. Operators can, at their discretion, plan these tests to coincide with the performance of their annual state MIT requirements as long as the time requirements are met. The falloff testing report should be submitted no later than 60 days following the test. Failure to submit a falloff test report will be considered a violation of the applicable petition condition and may result in an enforcement action. Any exceptions should be approved by EPA prior to conducting the test.

8.4 Falloff Test Report Requirements

In general, the report to EPA should provide general information and an overview of the falloff test, an analysis of the pressure data obtained during the test, a summary of the test results, and a comparison of the results with the parameters used in the no migration demonstration. Some of the following operator and well data will not change so once acquired, it can be copied and submitted with each annual report. The falloff test report should include the following information:

1. Company name and address
2. Test well name and location
3. The name and phone number of the facility contact person. The contractor contact may be included if approved by the facility in addition to a facility contact person.
4. A photocopy of an open hole log (SP or Gamma Ray) through the injection interval illustrating the type of formation and thickness of the injection interval. The entire log is not necessary.
5. Well schematic showing the current wellbore configuration and completion information:
   - Wellbore radius
   - Completed interval depths
   - Type of completion (perforated, screen and gravel packed, open hole)
6. Depth of fill depth and date tagged.
7. Offset well information:
   - Distance between the test well and offset well(s) completed in the same interval or involved in an interference test
   - Simple illustration of locations of the injection and offset wells
8. Chronological listing of daily testing activities.
9. Electronic submission of the raw data (time, pressure, and temperature) from all pressure gauges utilized on a memory stick or CD-ROM. A READ.ME file or the disk label should list all files included and any necessary explanations of the data. A separate file containing any edited data used in the analysis can be submitted as an additional file.
10. Tabular summary of the injection rate or rates preceding the falloff test. At a minimum, rate information for 48 hours prior to the falloff or for a time equal to twice the time of the falloff test is recommended. If the rates varied and the rate information is greater than 10 entries, the rate data should be submitted electronically as well as a hard copy of the rates for the report. Including a rate vs time plot is also a good way to illustrate the magnitude and number of rate changes prior to the falloff test.
11. Rate information from any offset wells completed in the same interval. At a minimum, the injection rate data for the 48 hours preceding the falloff test should be included in a tabular and electronic format. Adding a rate vs time plot is also helpful to illustrate the rate changes.

12. Hard copy of the time and pressure data analyzed in the report.
13. Pressure gauge information:
    - List all the gauges utilized to test the well
    - Depth of each gauge
    - Manufacturer and type of gauge. Include the full range of the gauge.
    - Resolution and accuracy of the gauge as a % of full range.
    - Calibration certificate and manufacturer's recommended frequency of calibration
14. General test information:
    - Date of the test
    - Time synchronization: A specific time and date should be synchronized to an equivalent time in each pressure file submitted. Time synchronization should also be provided for the rate(s) of the test well and any offset wells.
    - Location of the shut-in valve (e.g., note if at the wellhead or number of feet from the wellhead)
15. Reservoir parameters (determination):
    - Formation fluid viscosity
    - Porosity, (well log correlation or core data)
    - Total compressibility
    - Formation volume factor
    - Initial formation reservoir pressure
    - Date reservoir pressure was last stabilized (injection history)
    - Justified interval thickness
16. Waste plume:
    - Cumulative injection volume into the completed interval
    - Calculated radial distance to the waste front
    - Average historical waste fluid viscosity, if used in the analysis
17. Injection period:
    - Time of injection period
    - Type of test fluid
    - Type of pump used for the test (e.g., plant or pump truck)
    - Type of rate meter used
    - Final injection pressure and temperature
18. Falloff period:
    - Total shut-in time, expressed in real time and
    - Final shut-in pressure and temperature
    - Time well went on vacuum, if applicable
19. Pressure gradient:
    - Gradient stops - for depth correction
20. Calculated test data: include all equations used and the parameter values assigned for each variable within the report
    - Radius of investigation
    - Slope or slopes from the semilog plot
    - Transmissibility
    - Permeability

- Calculation of skin
- Calculation of skin pressure drop
- Discussion and justification of any reservoir or outer boundary models used to simulate the test
- Explanation for any pressure or temperature anomaly if observed

21. Graphs:
    - Cartesian plot: pressure and temperature vs. time
    - Log-log diagnostic plot: pressure and semilog derivative curves. Radial flow regime should be identified on the plot
    - Semilog and expanded semilog plots: radial flow regime indicated and the semilog straight line drawn
    - Injection rate(s) vs time: test well and offset wells (not a circular or strip chart)
22. A comparison of all parameters with those used in the petition demonstration, including references where the parameters can be found in the petition.
23. A copy of the latest radioactive tracer run to fulfill the annual mechanical integrity testing requirement for the State and a brief discussion of the results.
24. Compliance with any unusual petition approval conditions such as the submission of an annual flow profile survey. These additional conditions may be addressed either in the annual falloff testing report or in an accompanying document.

8.5 Planning

The radial flow portion of the test is the basis for all pressure transient calculations. Therefore, the injectivity and falloff portions of the test should be designed not only to reach radial flow, but to sustain a time frame sufficient for analysis of the radial flow period.

General Operational Concerns

Successful well testing involves the consideration of many factors, most of which are within the operator's control. Some considerations in the planning of a test include:

- Adequate storage for the waste should be ensured for the duration of the test
- Offset wells completed in the same formation as the test well should be shut-in, or at a minimum, provisions should be made to maintain a constant injection rate prior to and during the test
- Install a crown valve on the well prior to starting the test so the well does not have to be shut-in to install a pressure gauge
- The location of the shut-in valve on the well should be at or near the wellhead to minimize the wellbore storage period
- The condition of the well, junk in the hole, wellbore fill or the degree of wellbore damage (as measured by skin) may impact the length of time the well must be shut-in for a valid falloff test. This is especially critical for wells completed in relatively low transmissibility reservoirs or wells that have large skin factors.
- Cleaning out the well and acidizing may reduce the wellbore storage period and therefore the shut-in time of the well
- Accurate recordkeeping of injection rates is critical including a mechanism to synchronize times reported for injection rate and pressure data. The elapsed time format usually reported for pressure data does not allow an easy synchronization with

real time rate information. Time synchronization of the data is especially critical when the analysis includes the consideration of injection from more than one well.

- Any unorthodox testing procedure, or any testing of a well with known or anticipated problems, should be discussed with EPA staff prior to performing the test.
- Other pressure transient tests may be used in conjunction or in place of a falloff test in some situations. For example, if surface pressure measurements must be used because of a corrosive wastestream and the well will go on vacuum following shut-in, a multi-rate test may be used so that a positive surface pressure is maintained at the well.
- If more than one well is completed into the same reservoir, operators are encouraged to send at least two pulses to the test well by way of rate changes in the offset well following the falloff test. These pulses will demonstrate communication between the wells and, if maintained for sufficient duration, they can be analyzed as an interference test to obtain interwell reservoir parameters.

8.6 Pretest Planning

1. Determine the time needed to reach radial flow during the injectivity and falloff portions of the test:

    - Review previous well tests, if available

    - Simulate the test using measured or estimated reservoir and well completion parameters

    - Calculate the time to the beginning of radial flow using the empirically-based equations. The equations are different for the injectivity and falloff portions of the test with the skin factor influencing the falloff more than the injection period.

    - Allow adequate time beyond the beginning of radial flow to observe radial flow so that a well-developed semi log straight line occurs. A good rule of thumb is 3 to 5 times the time to reach radial flow to provide adequate radial flow data for analysis.

2. Adequate and consistent injection fluid should be available so that the injection rate into the test well can be held constant prior to the falloff. This rate should be high enough to produce a measurable falloff at the test well given the resolution of the pressure gauge selected. The properties of the fluid should be consistent. Any mobility issues should be identified and addressed in the analysis if necessary.

3. Bottomhole pressure measurements are usually superior to surface pressure measurements because bottomhole measurements tend to be less noisy. Surface pressure measurements can be used if positive pressure is maintained at the surface throughout the falloff portion of the test. The surface pressure gauge should be located at the wellhead.

4. A surface pressure gauge may also serve as a backup to a downhole gauge and provide a monitoring tool for tracking the test progress. Surface gauge data can be plotted during the falloff in a log-log plot format with the pressure derivative function to determine if

the test has reached radial flow and can be terminated. Note: Surface pressure measurements are not adequate if the well goes on a vacuum during the test.

5. Use two pressure gauges during the test with one gauge serving as a backup, or for verification in cases of questionable data quality. The two gauges do not need to be the same type.

8.7 Conducting the Falloff Test

1. Tag and record the depth to any fill in the test well
2. Simplify the pressure transients in the reservoir
   - Maintain a constant injection rate in the test well prior to shut-in. This injection rate should be high enough and maintained for a sufficient duration to produce a measurable pressure transient that will result in a valid falloff test.
   - Offset wells should be shut-in prior to and during the test. If shut-in is not feasible, a constant injection rate should be recorded and maintained during the test and then accounted for in the analysis.
   - Do not shut-in two wells simultaneously or change the rate in an offset well during the test.
3. The well must be shut-in at the wellhead or as near to the wellhead as feasible in order to minimize wellbore storage and after flow. The shut-in must be accomplished as instantaneously as possible to prevent erratic pressure behavior during the test.
4. Maintain accurate rate records for the test well and any offset wells completed in the same injection interval.
5. Measure and record the properties of the injectate periodically during the injectivity portion of the test to confirm the consistency of the test fluid.
6. The surface readout downhole pressure gauge must be located at or near the top of the injection interval, unless previous testing indicates a more appropriate location. A surface readout should be provided to allow flexibility in determining appropriate pressure measuring and recording time intervals and to ensure valid test data is generated and false testing runs can be identified and aborted.
7. The injection rate and injection liquid density for the test must be held constant prior to shut-in.
8. The injection rate must be high enough and continuous for a period of time sufficient to produce a pressure buildup that will result in valid test data.

9. The injection rate must result in a pressure buildup such that a semi log straight line can be determined from the Horner plot. The injection rate should be the maximum injection rate that can be feasibly maintained constant in order to maximize pressure changes in the formation and provide valid test results, but not exceeding the daily injection volume limit of the UIC Permit.

10. If the stabilization injection period is interrupted, for any reason and for any length of time, the stabilization injection period must be restarted.

11. The fall-off portion of the test must be conducted for a length of time sufficient such that the pressure is no longer influenced by wellbore storage or skin effects and enough data points lie within the infinite acting period and the semi log straight line is well developed.

8.8 Evaluation of the Test Results

A licensed geologist or licensed professional engineer, licensed by the Board for Professional Engineers, Land Surveyors, and Geologists to practice geology or engineering in California and knowledgeable in the methods of pressure transient test analysis, must evaluate the test results.

The following information and evaluations must be provided with the test report:

1. Prepare a Cartesian plot of the pressure and temperature versus real time or elapsed time.
    - Confirm pressure stabilization prior to shut-in of the test well
    - Look for anomalous data, pressure drop at the end of the test, determine if pressure drop is within the gauge resolution
2. Prepare a log-log diagnostic plot of the pressure and semi log derivative. Identify the flow
    - regimes present in the well test
    - Use the appropriate time function depending on the length of the injection period and variation in the injection rate preceding the falloff.
    - Mark the various flow regimes - particularly the radial flow period
    - Include the derivative of other plots, if appropriate (e.g., square root of time for linear flow)
    - If there is no radial flow period, attempt to type curve match the data
3. Prepare a semi log plot.
    - Use the appropriate time function depending on the length of injection period and injection rate preceding the falloff
    - Draw the semi log straight line through the radial flow portion of the plot and obtain the slope of the line
    - Calculate the transmissibility
    - Calculate the skin factor
    - Calculate the radius of investigation, "r"
4. Explain any anomalous data responses. The analyst should investigate physical causes other than reservoir responses.

5. All equations used in the analysis must be provided with the appropriate parameters substituted in them.

Note: Tests conducted in relatively transmissive reservoirs are more sensitive to the temperature compensation mechanism of the gauge, because the pressure buildup response evaluated is smaller. For this reason, the plot of the temperature data should be reviewed. Any temperature anomalies should be noted to determine if they correspond to pressure anomalies.

Compliance with any unusual petition approval conditions such as the submission of an annual flow profile survey. These additional conditions may be addressed either in the annual falloff testing report or in an accompanying document.

8.9 Comparison of Fall Off Results to no Migration Petition Data

A comparison between the falloff test results and the parameters used in the no migration petition demonstration should be made. Specifically, the following should be demonstrated:

- Both the flowing and static bottom hole pressures measured during the test should be corrected for skin and be at or below those which were predicted to occur by the pressure buildup model in the provided no migration petition for the same point in time.
- It should be shown that the (kh/*) parameter group calculated from the current falloff data is the same or greater than that employed in the pressure buildup modeling

9. Carbon Dioxide Plume and Pressure Front Tracking

CES will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure during the operation period to meet the requirements of 40 CFR 146.90(g).

9.1 Plume monitoring location and frequency

Table 9 presents the methods that CES will use to monitor the migration of the CO_2 plume, including the activities, locations, and frequencies CES will employ. The parameters to be analyzed as part of fluid sampling in the injection zone and associated analytical methods are presented in Table 8.

9.2 Plume monitoring details

CES will conduct fluid sampling and analysis to detect changes in groundwater in order to directly monitor the carbon dioxide plume. The parameters to be analyzed as part of fluid sampling in the Panoche sand (i.e., the injection zone) and analytical methods are presented in Table 10.

Indirect plume monitoring will be employed using pulsed neutron capture logs to monitor CO_2 saturation. Time-lapse surface 3D seismic or vertical seismic profiles (borehole VSPs) in the monitoring wells will also be used to image the developing CO_2 plume for indirect plume monitoring. The baseline 3D seismic survey should cover a large enough area to encompass calibration wells and potential migration pathways plus offset features such as sub-regional faulting (likely 12-15 square miles). Subsequent time-lapse seismic monitoring (3D surface or 3D VSP) can be constrained to an ‘image area’ (with 3D migration processing) with coverage sufficient to cover the growing plume (considerably smaller ~ 100 to 2000 acres based on modeling and projected plume size).

Table 9: Plume monitoring activities.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
DIRECT PLUME MONITORING				
Panoche	Fluid sampling	OBS_1	1-point location, 1 interval: -9300 ~ -9600 MSL	Annual
INDIRECT PLUME MONITORING				
Panoche	Pulse Neutron Logging	INJ_1	1-point location (9.625" outside wellbore) & continuous to full well depth	Annual
		OBS_1	1-point location (8.5" outside wellbore) & continuous to full well depth	Annual
Multiple	Time-lapse VSP survey	OBS_1	Monitor 3D VSP survey image area ~ 100 to 2000 acres	Baseline, Year 2, 3, 4
Multiple	3D surface seismic survey, or combination surface and well VSP	Full coverage focusing on the northern extent of plume area	Fold Image Coverage: Baseline ~ 15 square miles. Monitor 3D survey image area ~ 2,000+ acres	Baseline, Year 3

Note 1: Baseline monitoring will be completed before injection is authorized.

Note 2: Annual monitoring will be performed up to 45 days before the anniversary date of authorization of injection each year or alternatively scheduled with the prior approval of the UIC Program Director.

Note 3: Logging surveys will take place up to 45 days before the anniversary date of authorization of injection each year or alternatively scheduled with the prior approval of the UIC Program Director.

Note 4: Seismic surveys will be performed in the 4th quarter before or the 1st quarter of the calendar year shown or alternatively scheduled with the prior approval of the UIC Program Director.

Table 10: Summary of analytical and field parameters for fluid sampling in the injection zone.

Parameters	Analytical Methods [1]
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, and Tl	ICP-MS, EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B
Anions: Br, Cl, F, NO_3, and SO_4	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	Coulometric titration, ASTM D513-11
Isotopes: $\delta^{13}C$ of DIC	Isotope ratio mass spectrometry
Total Dissolved Solids	Gravimetry; APHA 2540C
Water Density (field)	Oscillating body method
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple

Note 1: ICP = inductively coupled plasma; MS = mass spectrometry; OES = optical emission spectrometry; GC-P = gas chromatography - pyrolysis. An equivalent method may be employed with the prior approval of the UIC Program Director.

Figure 3 shows the predicted CO_2 plume and pressure front (ΔPc=3.5 psi) after 6 months of injection. To capture the CO_2 plume migration within this timeframe, appropriate monitoring locations relative to the CO_2 plume and pressure front would be approximately 1000 ft to the north and northeast from the injection well. Figure 4 ~ Figure 7 show the temporal evolution of CO_2 plume and pressure front at 5, 20, 30, and 70 years after the commencement of CO_2 injection.

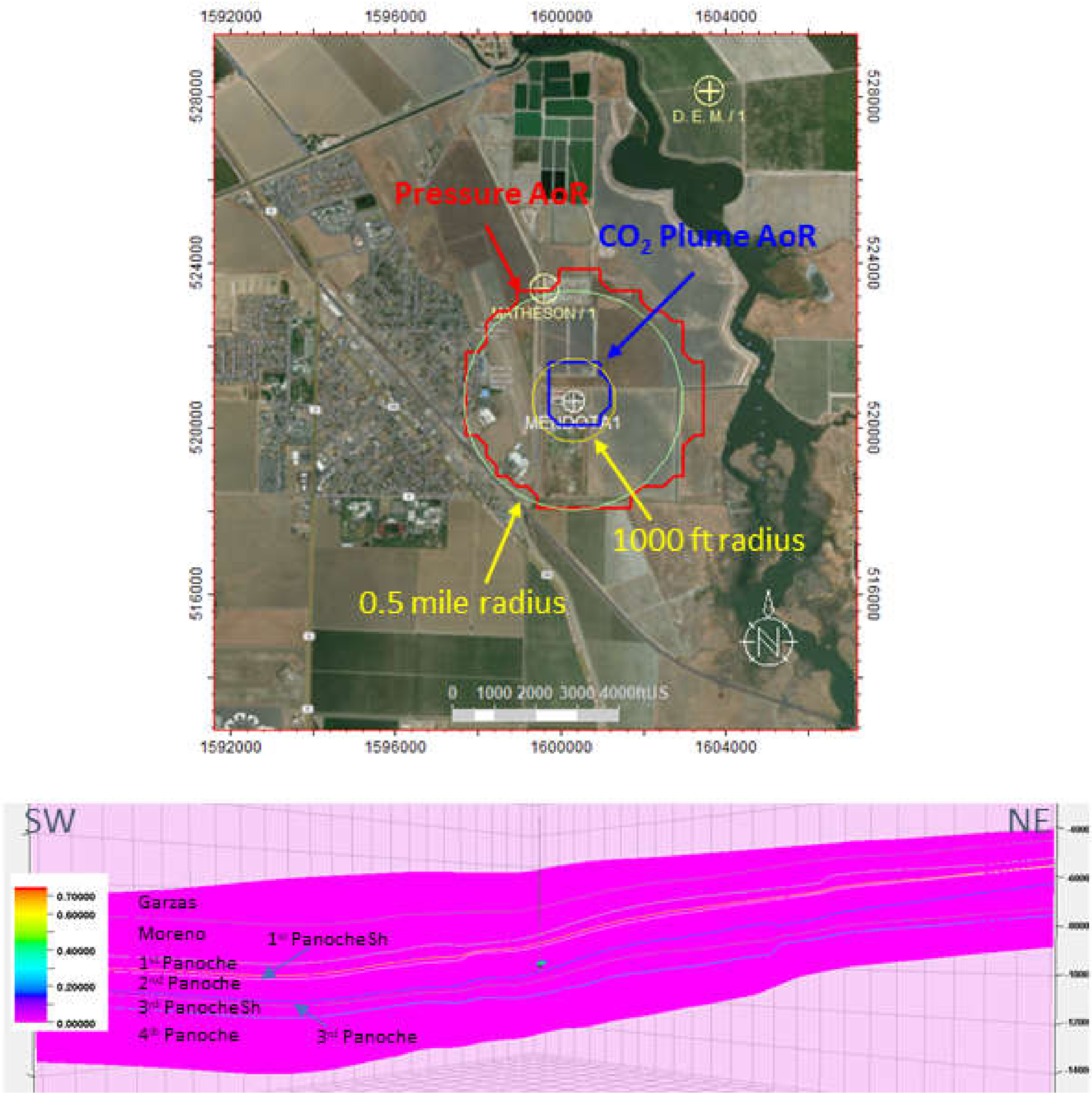
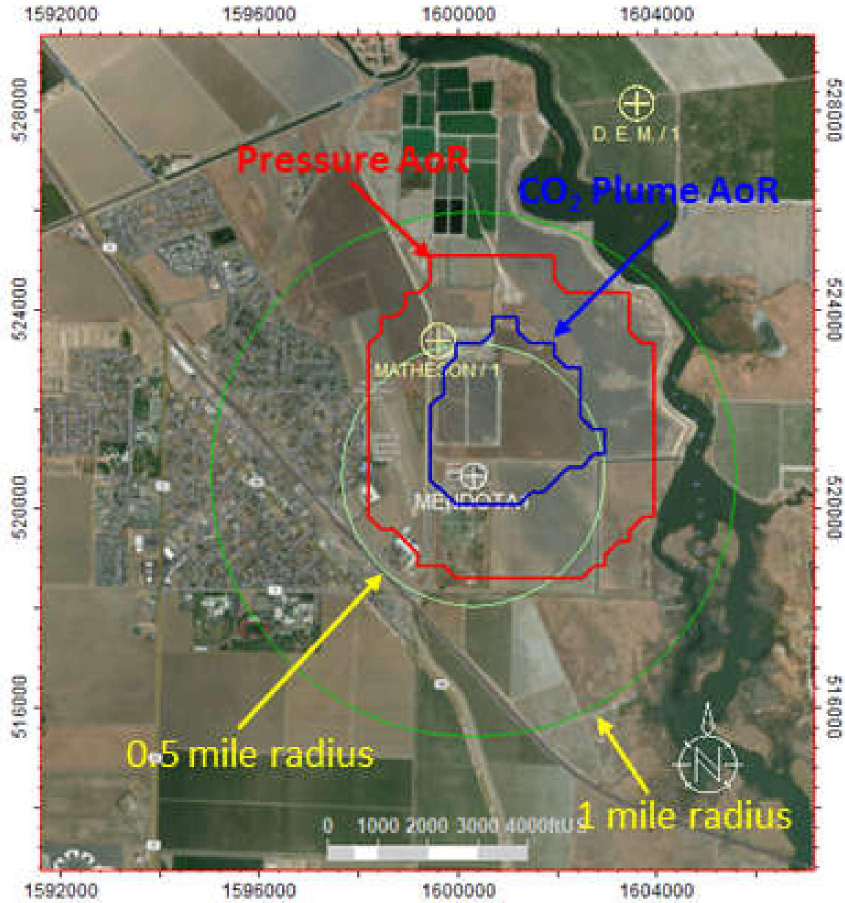


Figure 3: Predicted extent of the CO_2 plume and pressure front (ΔPc = 3.5 psi) after 6 months of injection.



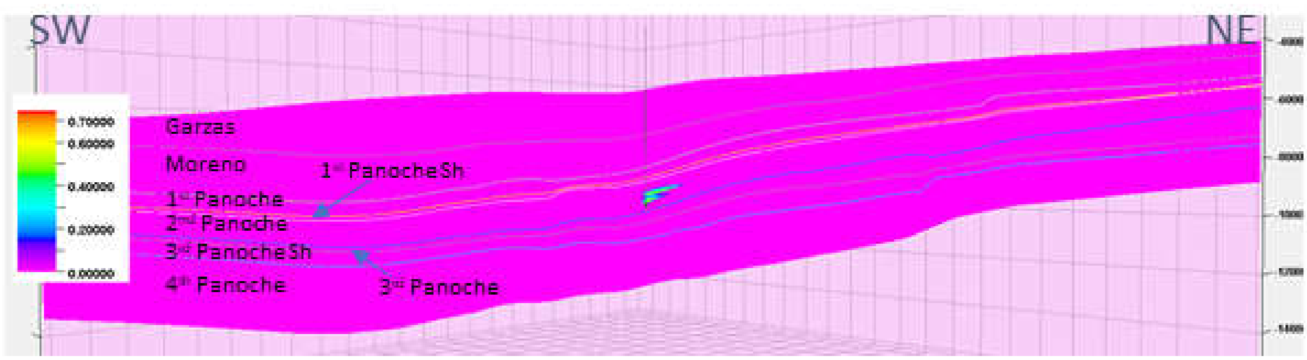


Figure 4: Predicted extent of the CO_2 plume and pressure front ($\Delta Pc = 3.5$ psi) after 5 years of injection.

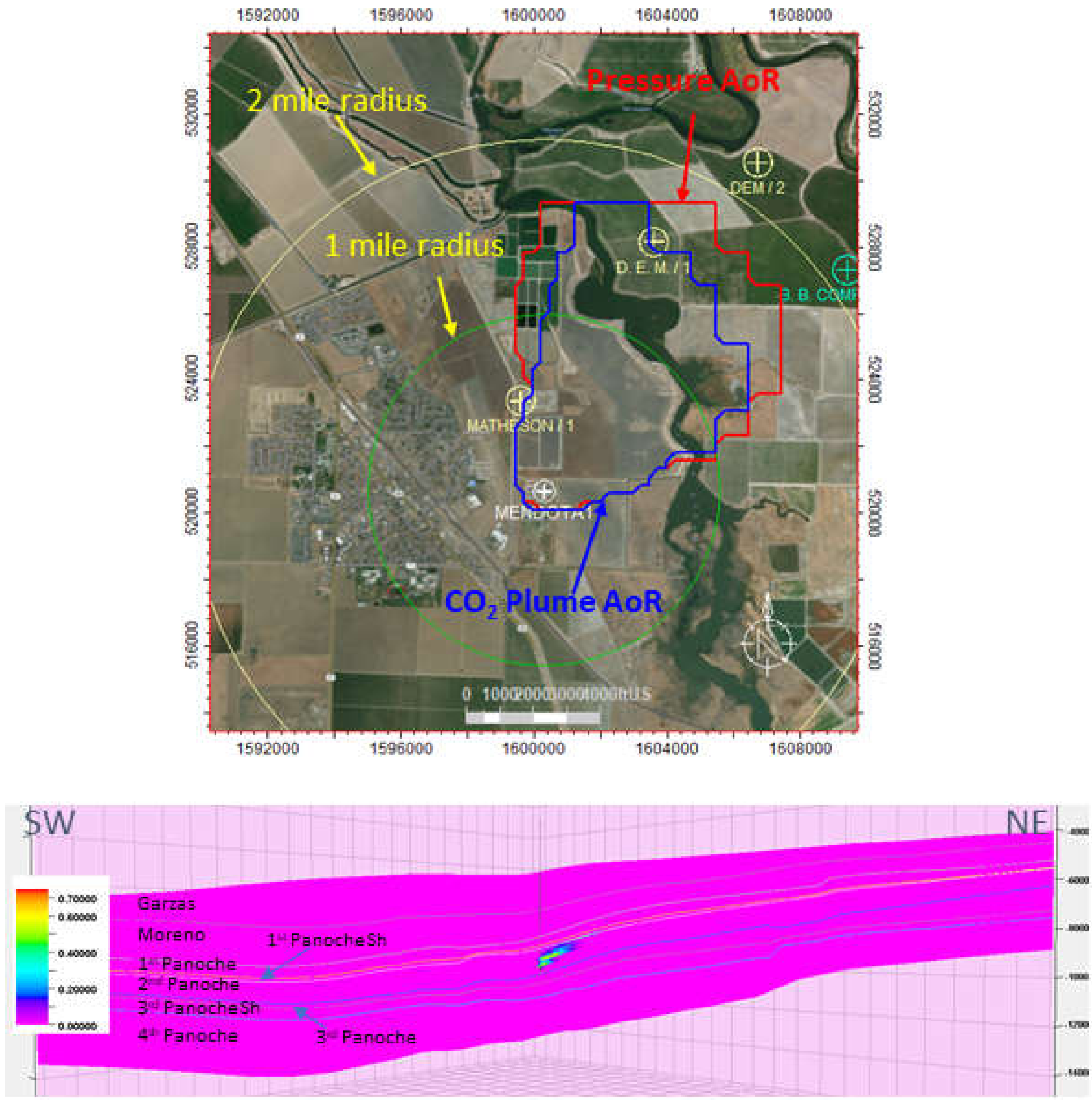


Figure 5: Predicted extent of the CO_2 plume and pressure front (ΔPc = 3.5 psi) after 20 years of injection.

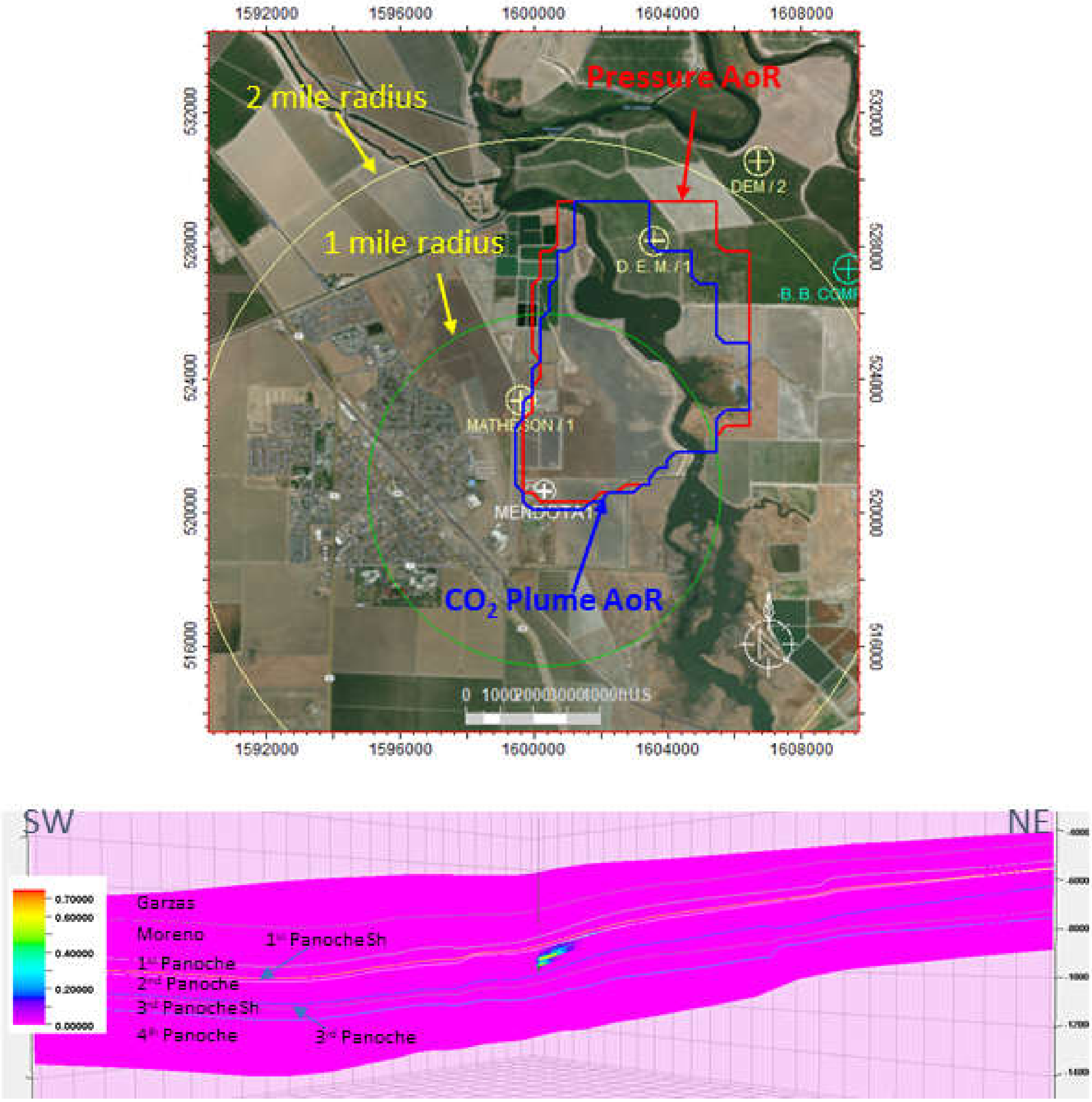
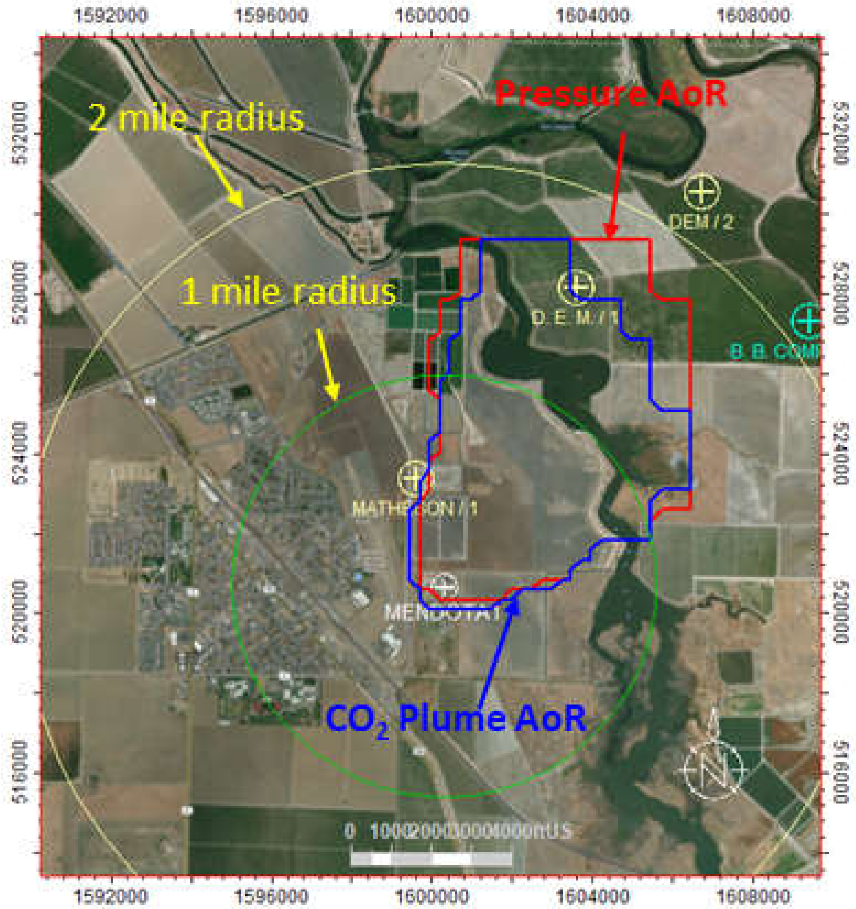


Figure 6: Predicted extent of the CO_2 plume and pressure front ($\Delta Pc = 3.5$ psi) after 10 years of post-injection.



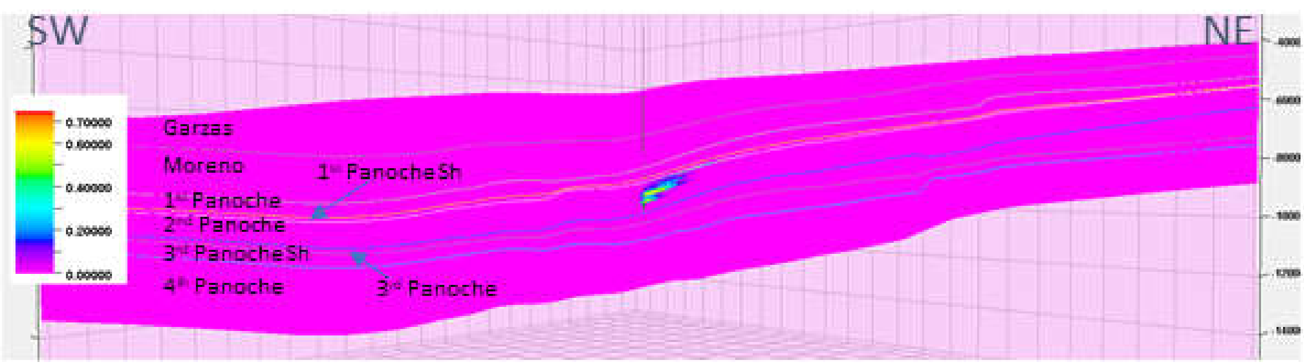


Figure 7: Predicted extent of the CO_2 plume and pressure front (ΔPc = 3.5 psi) after 50 years of post-injection.

9.3 Pressure-front monitoring location and frequency

Table 11 presents the methods that CES will use to monitor the position of the pressure front, including the activities, locations, and frequencies CES will employ. The (Schlumberger Quality Assurance and Surveillance Plan, 2020) requires site specific data that has not been collected in this prepermitting phase of this project. Once these data are collected in future phases of this project, CES will have the details necessary to develop a comprehensive Quality Assurance and Surveillance Plan.

9.4 Pressure-front monitoring details

CES will deploy pressure/temperature monitors and DTS to directly monitor the position of the pressure front. Predicted bottom-hole pressure profiles at proposed injection well is shown in Figure 8. Passive seismic monitoring combination of borehole and surface seismic stations to detect local events over M 1.0 within the AoR will also be performed.

Table 11: Pressure-front monitoring activities.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Direct Pressure-Front Monitoring				
Panoche Formation (Panoche Sands 1, 2, and 3)	Pressure/ temperature monitoring	OBS_1	1 point location, 3 intervals: (~ -8600, -9400, -10000 MSL)	Continuous
Panoche Injection Interval	Pressure/ temperature monitoring	INJ_1	1 point location, 1 interval: PT @ Perfs (~ -9400-9620 MSL)	Continuous
Multiple	Distributed Temperature Sensing (DTS)	OBS_1	1 point location, distributed measurement to -9000 MSL.	Continuous
		INJ_1	1 point location, distributed measurement to 9400 KB/-9200 MSL	Continuous
Other Plume/Pressure-Front Monitoring				
Multiple	Passive seismic	A combination of borehole and surface seismic stations	The passive seismic monitoring system has the ability to detect seismic events over M1.0 within the AoR.	Continuous

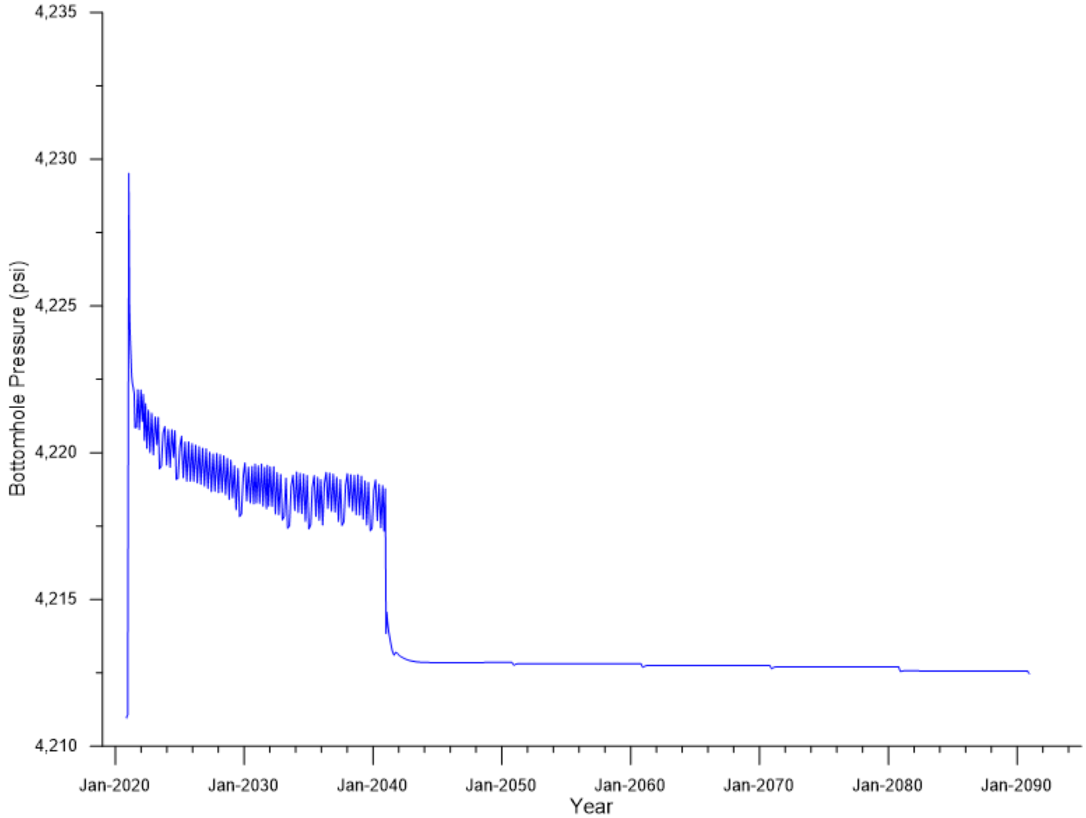


Figure 8: Predicted bottomhole pressure profile at the middle of the injection interval, simulated for 70 years after the commencement of injection (20-year injection and 50-year post-injection).

10. Appendix: Quality Assurance and Surveillance Plan

The (Schlumberger Quality Assurance and Surveillance Plan, 2020) requires site specific data that has not been collected in this prepermitting phase of this project. Once these data are collected in future phases of this project, CES will have the details necessary to develop a comprehensive Quality Assurance and Surveillance Plan.

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